

VIRGINIA OFFSHORE WIND INTEGRATION STUDY



Dominion Virginia Power
Electric Transmission Planning Department
November 30, 2010

Introduction:

The 2010 Virginia General Assembly established the Virginia Offshore Wind Development Authority (VOWDA) to promote the development of wind resources off Virginia's Atlantic coast. The Act authorizes the Virginia Department of Mines, Minerals and Energy (DMME) to request an incumbent utility to initiate a transmission study to determine the potential interconnection options for multiple offshore wind facilities to the transmission grid. Dominion Virginia Power (DVP) received a letter from DMME, dated May 27, 2010, to perform such a study. DVP is the Commonwealth of Virginia's largest investor owned electric utility and provides service to over 2.4 million retail electric customers located throughout Virginia and the northeastern part of North Carolina. In 2005, DVP integrated its transmission and generation facilities into the PJM regional transmission organization (RTO). PJM operates the world's largest energy market and coordinates the movement of electricity across thirteen states and the District of Colombia. Generation interconnections to the transmission system are governed by Federal Energy Regulatory Commission (FERC) approved tariffs. Under a federally approved process, all new generation facilities must file a request for interconnection and enter the request into the PJM Generation Queue.

Study Scope:

Through this study, DVP evaluates potential locations for integrating multiple wind generation facilities with DVP's transmission system located in the South Hampton Roads area of Virginia. This study also identifies potential transmission constraints (deficiencies) that may occur and need to be resolved to reliably interconnect wind generation facilities with the Company's transmission system. This study does not evaluate potential fault current issues (over dutied equipment) and system stability. Nor is this study a substitute for PJM's generation interconnection processes. As a PJM member any generator that seeks to interconnect with the Company's transmission system must file an interconnection request in PJM's Generation Interconnection Queue. These study results are only meant to provide potential wind generation developers off the Virginia coast with guidance on potential options and impacts regarding interconnection of their projects with the Dominion transmission system. The results of this analysis were based on information on the transmission system at the time this report was

developed. It is possible that, depending on timing, a particular offshore wind request in the PJM generation queue could produce different results. This study will not evaluate the transmission facilities that need to be constructed from the offshore wind site to the point of interconnection with Dominion's transmission system. Rather, the study focuses on the impact with injecting wind capacity into Dominions transmission system. See Figure A. (general diagram).

Generation in the PJM market has two components, capacity (C) and energy (E). Capacity refers to the average generation output which can be counted on to reliably serve peak demand across the entire PJM footprint. For wind generation facilities located in the PJM system, the RTO has determined the capacity value is equal to 13.4% of the nominal generation output. Therefore, a wind generation facility with a total installed capability of 100 MW will be viewed as a 13.4 MW generation unit for a generation interconnection analysis and has the ability to receive capacity payments for this value. The 13.4% capacity value was determined by PJM as the average amount of wind generation during summer peak conditions that can be reasonably assured to be available to serve load. It should be noted that this 13.4% is a factor used for onshore wind and higher capacity factors for offshore wind resources are likely. Only this portion of the generation will receive capacity payments and be counted as a firm resource able to serve load anywhere in PJM. The additional 86.6 MW output of the hypothetical 100 MW facility would be considered an energy injection into the transmission system. Due to the intermittency of the wind, these energy injections are not considered as reliable resources for serving peak demand across the PJM service area. Energy resources are studied only at the point of potential injection.

A generation developer is required by PJM to resolve any transmission constraints identified as part of the capacity analysis. Any transmission constraints identified as part of the energy analysis are optional for the generation developer to resolve. However, if the generation developer chooses not to resolve these constraints, then the output of the generation facility may be reduced to resolve operational constraints in real time. Wind generation located off the coast is potentially thought to have a greater capacity factor than land based wind generation facilities. This study will assume a 33% capacity factor for its analysis, which is a conservative estimate based on current industry information. Attachment A is a copy of a recent PJM presentation on October 6, 2010 on an Off-Shore Wind Conceptual Study. This study includes some of the

DOE's results of their recent Eastern Wind Integration and Transmission Study (EWITS) Analysis.

Power Flow Case Assumptions:

Two power flow cases were developed for the DVP analysis. The first was a summer peak case and the second was a light load case. The light load case was developed to evaluate shoulder months for spring and fall typical load levels. The probable 2015 PJM Regional Transmission Expansion Planning (RTEP) case was used as the starting point for both cases. Dominion updated the current RTEP to include publically announced year 2015 transmission projects including any new generation that has proceeded to the Interconnection Service Agreement (ISA) phase of the PJM Generation Interconnection process. Transmission projects up through 2015 have a high probability of moving forward and it is important in the assessment portion to include these upgrades.

In order to take a longer planning view, the load in the peak case was also scaled up to forecasted year 2020 summer peak load for the PJM members system. The load forecast used came from the most recent PJM 2010 Load Forecast. Generation was scaled proportionally across the PJM System to ensure that load and generation remained in a balanced operating condition. This case was used for the capacity analysis.

For a light load, or shoulder month, case a peak system load equal to 80% of summer peak was developed. Generation in this case was also scaled proportionally across the PJM system. This case will be used for the energy analysis.

Finally, Attachment B is a copy of the Company's Planning Criteria. The Energy Policy Act of 2005 made compliance with NERC Reliability Criteria mandatory for transmission owners and subject to third party audits and fines up to \$ 1 million dollars per day for non-compliance.

Study Results

Dominion Virginia Power is currently in the process of completing two major projects in the South Hampton Roads area. The first project involves the construction of a new 500 kV line from Carson Substation (just south of Petersburg) to Suffolk Substation located in the city of

Suffolk. This project also includes the construction of a new 23 mile 230 kV line from Suffolk Substation to Thrasher Substation which is located in the city of Chesapeake east of the Elizabeth River. At Thrasher Substation several 230 kV lines will be networked to create a new transmission switching station. A second major project in this area will construct a new 230 kV line from Landstown Substation to Virginia Beach Substation. This project involves rebuilding the existing 115 kV line located between these two substations for a higher capacity. These two projects will significantly strengthen the transmission system located in the South Hampton Roads area.

Landstown Substation, located off of Dam Neck Road near the Virginia Beach Amphitheater, would be a natural location to interconnect proposed offshore wind facilities. While it may be possible to interconnect potential wind farms with different substations in the area, for study purposes, Landstown Substation was chosen as a potential interconnection point due to a number of electrical advantages. First, the substation is located near the ocean front and is in the middle of the study area off the Virginia coast identified for potential wind projects (see Figure D). As shown in Figure B, (Google Earth) additional land located near this substation would provide room for expansion to integrate new generation attachment facilities with the transmission system. Also this substation has multiple 230 kV lines bussed together which will provide a strong interconnection point for multiple generation interconnections (See Figure C). Regardless of location, the siting of new transmission interconnections in this area will present significant challenges due to its urban setting and many environmental constraints. The sections summarizing the study results are grouped together as A and B, and C and D. Sections A and C represent the capacity injections associated with the corresponding energy injections B and D. The energy injections correspond to the nominal nameplate rating (totalized) capability of the wind farm. The capacity injections are associated with the portion of the nominal capability of the wind farm that can reliably be counted on to serve load.

The reliability impact associated with a 2700 MW wind farm injecting its capacity and energy into the Landstown bus are shown in section A and B below.

- A. 900 MW Capacity Injection into Landstown 230 kV Bus: Based on using a capacity factor of 33%, in order to obtain 900 MW of dependable capacity will require the

wind farm installed capability to be 2700 MW (33% times 2700 MW equals 900 MW). The Summer 2020 case described above was used to determine the electrical impacts to the transmission system if 900 MW of new generation were injected into the Landstown 230 kV bus. Generation was scaled down proportional across the PJM System to account for this new generation. Reliability analysis consisted of studies which analyzed the impact of single contingencies, line fault with stuck breaker, and tower line contingencies on the reliability of the Company's transmission system.

- a. Single contingency: No issues were identified.
- b. Line fault with stuck breaker: No issues were identified.
- c. Tower line with two or more circuits: No issues were identified.

B. 2700 MW Energy Injection into the Landstown 230 kV Bus: The 2700 MW of energy represents the total nameplate of installed wind capability.

- a. Single contingency: Several transmission deficiencies were identified.

Contingency	Overloaded Line	Percent Overloaded
Yadkin to Thrasher 230 kV	Fentress to Landstown 230 kV	145%
Yadkin to Thrasher 230 kV	Landstown to Lynnhaven 230 kV	147%
Green Run to Lynnhaven 230 kV	Thrasher to Landstown 230 kV	147%

The estimated cost to resolve these deficiencies is \$ 30 million. This work would consist of building a second Fentress to Landstown 230 kV Line, building a second Thrasher to Landstown 230 kV line, and uprating the Landstown to Lynnhaven 230 kV line.

The reliability impact associated with a 4500 MW wind farm injecting its capacity and energy into the Landstown bus are shown in section C and D below.

C. 1500 MW Capacity Injection into the Landstown 230 kV Bus: Based on using a capacity factor of 33%, in order to obtain 1500 MW of dependable capacity will require the wind farm installed capability to be 4500 MW (33% times 4500 MW equals 1500 MW). The Summer 2020 case described above was used to determine the electrical impact of a proposed 1500 MW injection into the Landstown 230 kV bus. Generation was scaled down proportional across the PJM System to account for this new generation. Reliability analysis consisted of studies which analyzed the impact of single contingencies, line fault with stuck breaker, and tower line contingencies on the reliability of the Company's transmission system.

- a. Single contingency: No issues were identified.
- b. Line fault with stuck breaker: No issues were identified.
- c. Tower line with two or more circuits: No issues were identified.

D. 4500 MW Energy Injection into the Landstown 230 kV Bus: The 4500 MW of energy represents the total nameplate of installed wind capability.

- a. Single contingency: Several transmission deficiencies were identified.

Contingency	Overloaded Line	Percent Overloaded
Landstown to Fentress 230 kV	Fentress to Thrasher 230 kV	163%
Suffolk to Yadkin 500 kV	Fentress to Landstown 230 kV	161%
Yadkin to Thrasher 230 kV	Landstown to Lynnhaven 230 kV	166%
Landstown to Fentress 230 kV	Thrasher to Landstown 230 kV	321%
Green Run to Lynnhaven 230 kV	Lynnhaven to Thalia 230 kV	138%

The estimated cost to resolve these deficiencies is \$ 70 million. This work would consist of building a second Fentress to Landstown 230 kV Line, building a second Thrasher to Landstown 230 kV line and upgrading the Landstown to Lynnhaven 230 kV line; building a second Fentress to Thrasher 230 kV line; and rebuilding the Lynnhaven to Thalia 230 kV line.

From study sections A and B above, the results indicate that the integration of a 2700 MW wind farm located off the Virginia coast with Dominion's transmission system is feasible. Based on the conservative 33% capacity factor used in the study, a 2700 MW wind farm would correspond to 900 MW of capacity injection rights. At this 900 MW injection level, the study shows transmission infrastructure improvements would not be required. However, the closer this facility operates to its maximum capability of 2700 MW the more likely that the output would be restricted due to transmission constraints unless transmission infrastructure improvements are made. The developer(s) would have the option to fund transmission improvements for these higher MW levels, estimated to cost \$30 million, to increase the probability of the facility operating at its maximum energy output.

From study sections C and D above, the integration of a larger wind farm above the 2700 MW level becomes more challenging. Based on the conservative 33% capacity factor used in the study, a 4500 MW wind farm would correspond to 1500 MW of capacity injection rights. At this 1500 MW injection level, the study shows transmission infrastructure improvements would not be required. However, the closer this facility operates to its maximum capability of 4500 MW the more likely that the output would be restricted due to transmission constraints unless transmission infrastructure improvements are made. The developer(s) would have the option to fund transmission improvements for these higher MW levels, estimated to cost \$70 million, to increase the probability of the facility operating at its maximum energy output.

From a transmission planning and system operations perspective it would be prudent as the maximum capability of the wind facility approaches and exceeds 2700 MW that an additional location to inject power with the transmission system be strongly considered. Multiple connections would be more reliable to prevent single contingency events from losing large levels of generation. Fentress Substation, an integrated 230 kV and 500 kV substation, would be a good location to establish a second injection point to the transmission system. As shown in

Attachment A. PJM Interconnection also considered this substation when they evaluated multiple points along the East Coast for interconnection of a large wind power facility.

Conclusion:

This study concludes that the potential interconnection of a large-scale offshore wind facility with Dominion's transmission system in the Virginia Beach area is technically feasible. Whether this facility is one single wind facility or multiple smaller facilities, the aggregate generation amount is the factor that will drive transmission improvements. The results indicate that it is possible to interconnect large scale wind generation facilities up to a total installed capability of 4500 MW with the existing transmission system in the Virginia Beach area. The study recommends once the level of total wind generation capability exceeds 2700 MW, that multiple interconnections be considered. The study also indicates that when the actual output of the wind farm or farms approaches 2700 MW, there are greater probabilities that the output will have to be limited due to transmission constraints unless transmission infrastructure improvement are made. The developers of these wind farms will have to decide if they want to spend \$30 million to \$70 million to potentially minimize the amount of time that the output of the wind farms is restricted. From a dependable capacity analysis, the study shows that up to 1500 MW of generation injection into Landstown would not be expected to create transmission deficiencies.

This study's purpose is to provide high-level guidance on the feasibility of interconnecting a generation facility with the Company's transmission system in the Hampton Roads area. This study is in no way a substitute for a generation interconnection study with the Company's transmission system. Should a developer wish to determine its potential interconnection cost with the Dominion transmission system they will need to file an interconnection request in the PJM Generation Interconnection Queue. Although there may be others locations, this study highlights that the Landstown and Fentress Substations would be good locations to potentially interconnect generation.

Figure A

Simple One-Line

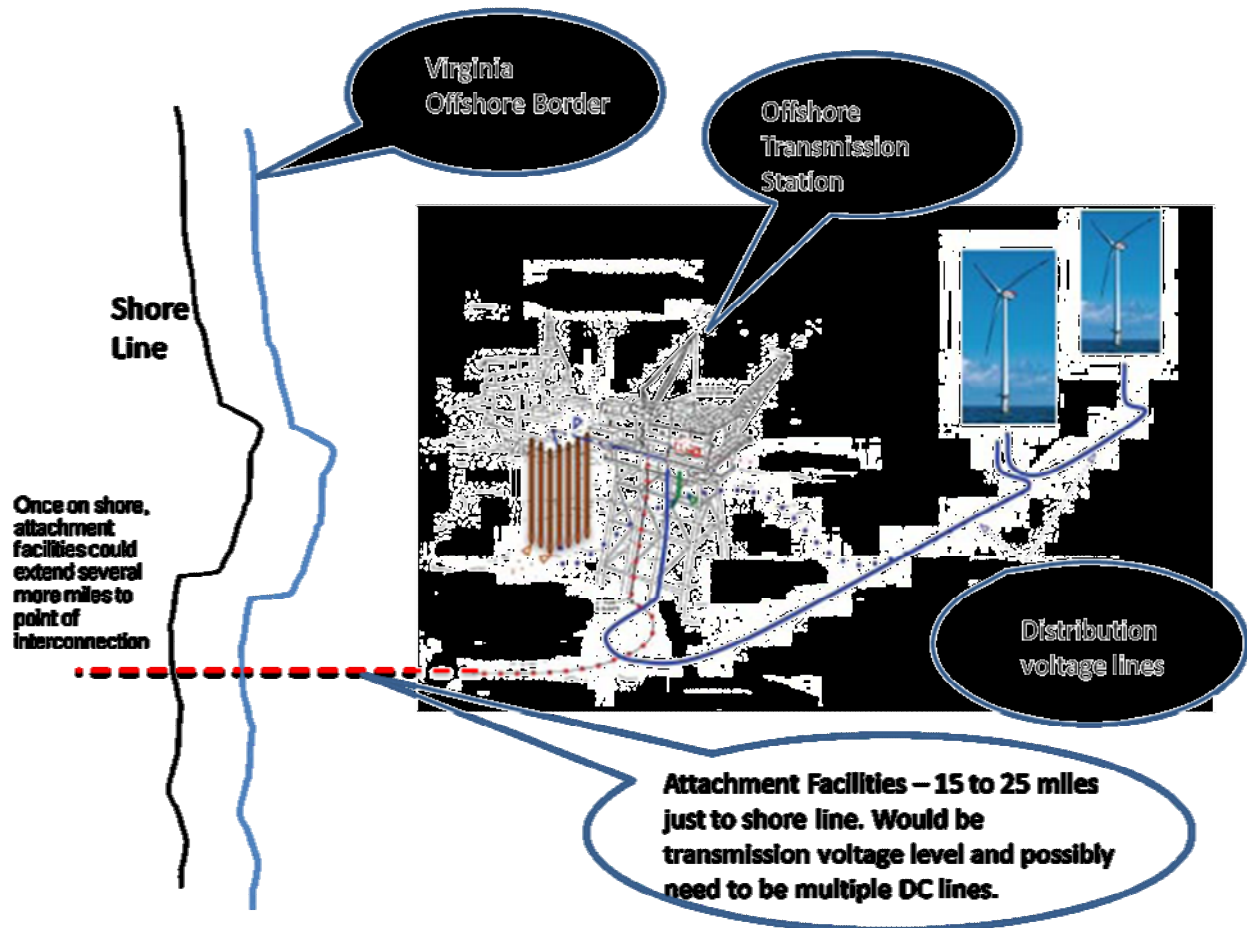
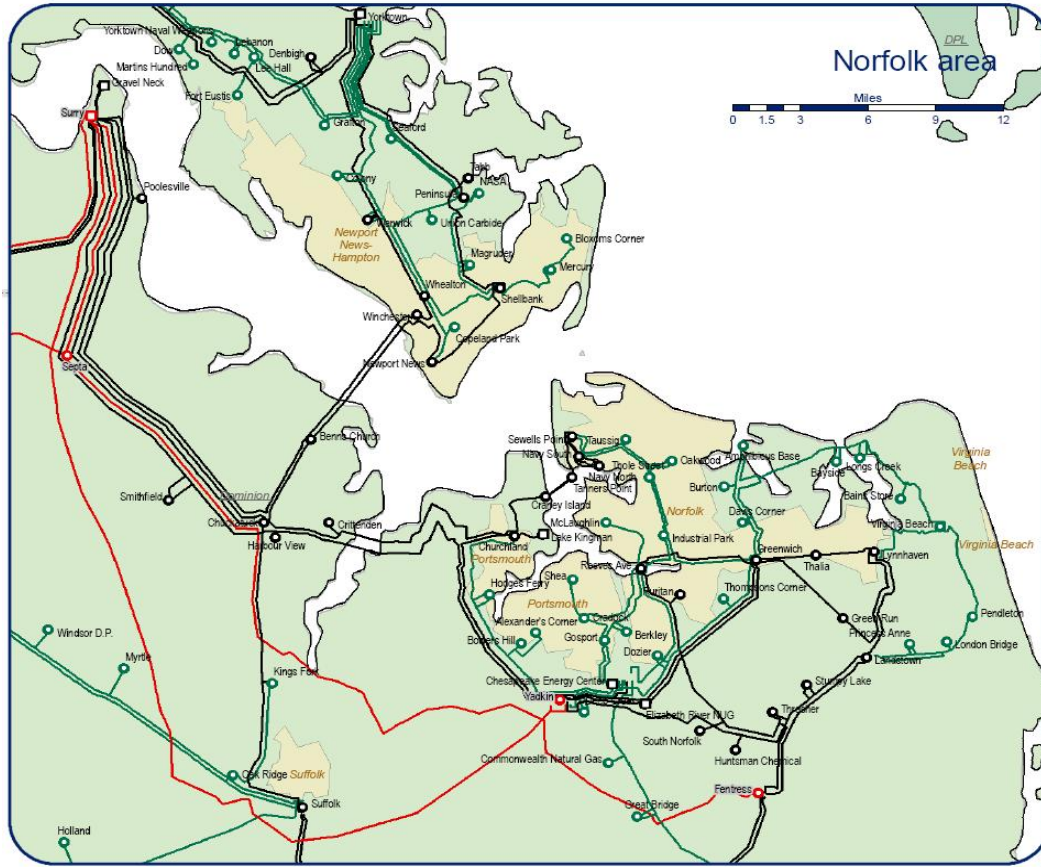


Figure B
Landstown Substation



Figure C

System Map

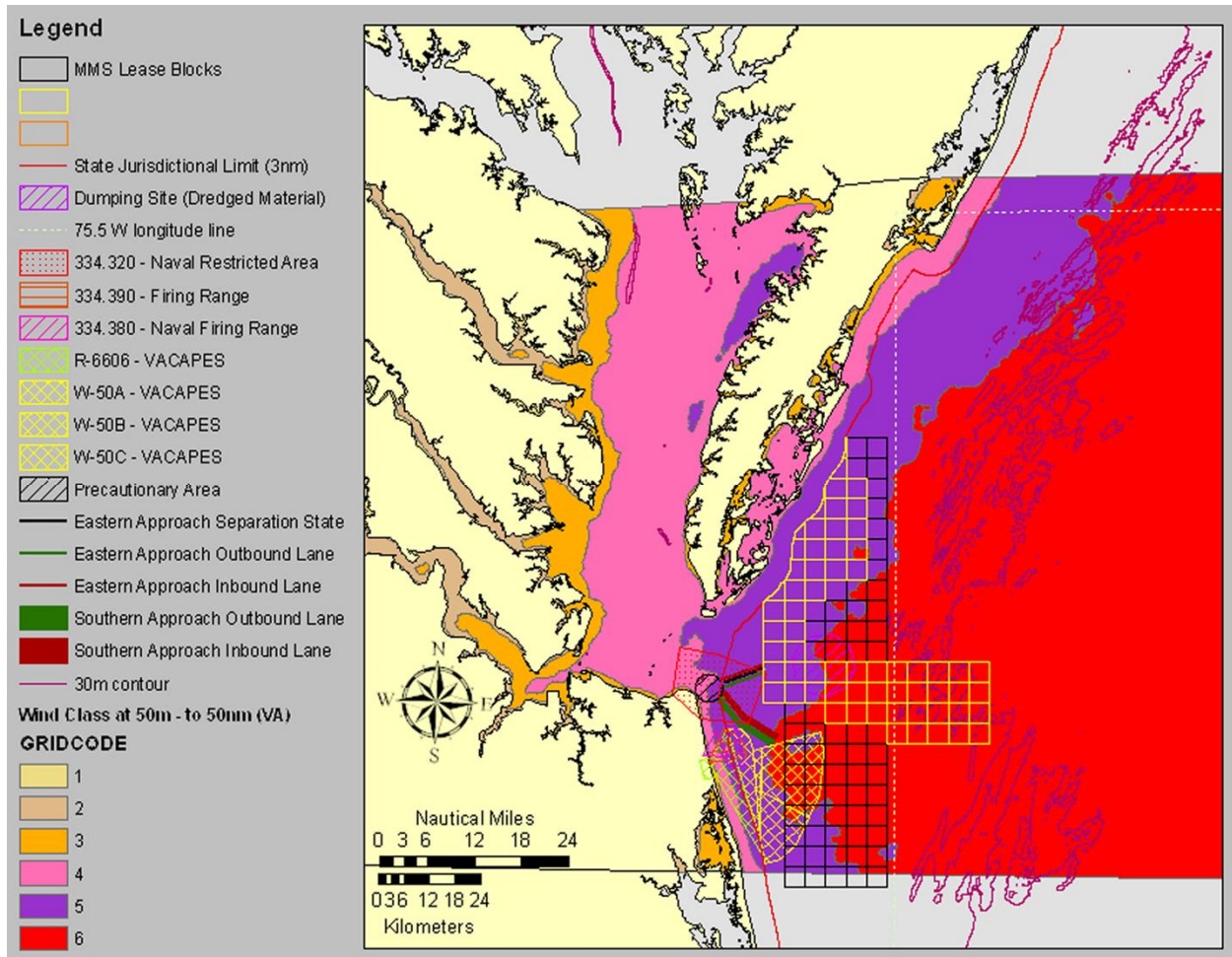


Legend



Figure D

Potential Wind Sites



Attachment A

PJM PRESENTATION

OFF-SHORE WIND CONCEPTUAL STUDY

INITIAL RESULTS

Off-Shore Wind Conceptual Study Initial Results



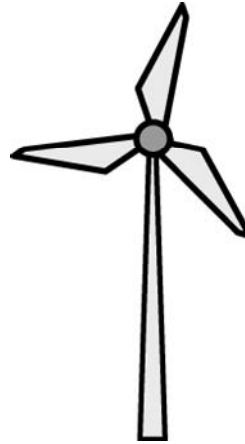
Paul McGlynn
October 1, 2010

Conceptual Offshore Wind Study Scope

- **Evaluate the reliability and market efficiency impact of offshore wind**
 - Reliability - Generator deliverability analysis
 - Market Efficiency - Promod production cost simulation

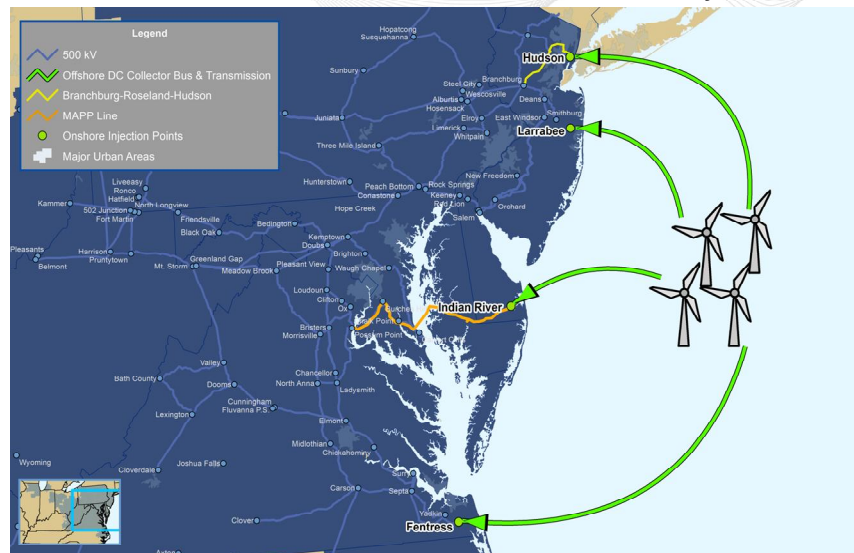


- Identify injection points to be studied where the offshore wind will interconnect with the existing transmission system.
- Perform reliability screening of single contingencies to identify potential constrained facilities.
- Utilize production cost simulation tools to evaluate the impact of the offshore wind

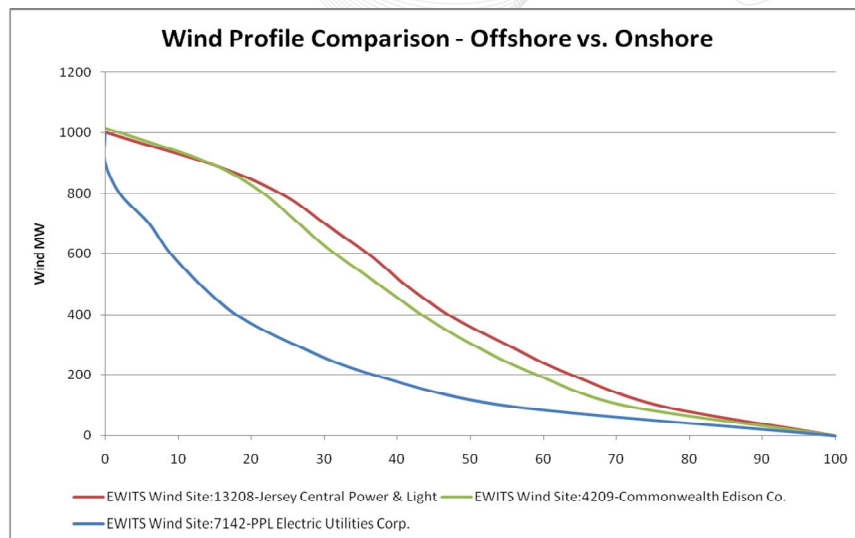


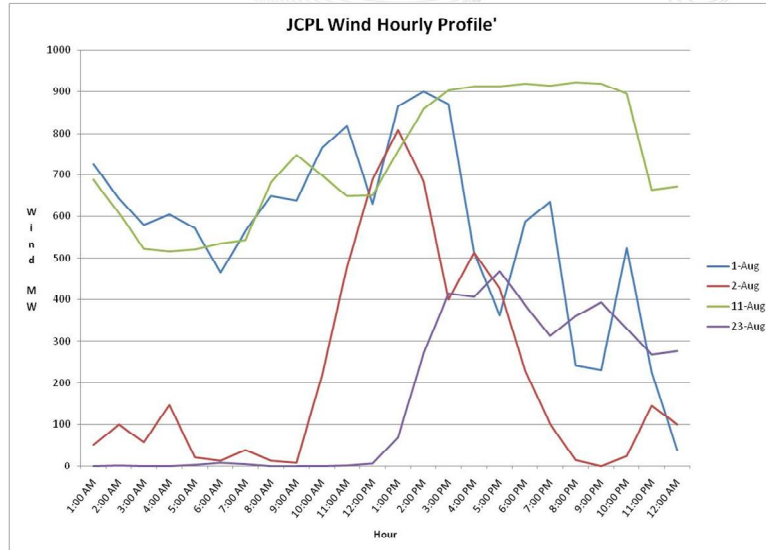
- Topology
 - Backbone Projects In-service
 - TRAIL
 - Carson - Suffolk
 - Susquehanna – Roseland
 - PATH
 - MAPP
 - Branchburg – Roseland – Hudson not included
 - Branchburg – Roseland – Hudson 230 kV alternative upgrades not included

- 2010 RTEP assumptions
 - Fuel prices per the May 27, 2009 TEAC
 - Load and energy forecast per the PJM 2010 Load Forecast Report
- Wind Profile
 - Used DOE offshore data developed for the EWITS



- Four scenarios tested
 - No wind (base system)
 - 10 GW
 - 20 GW
 - 30 GW
- Assumed four independent injection points



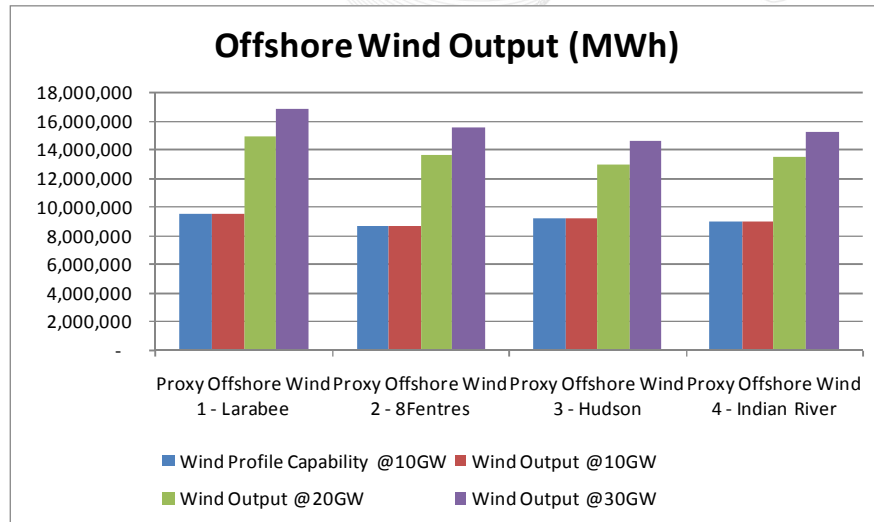


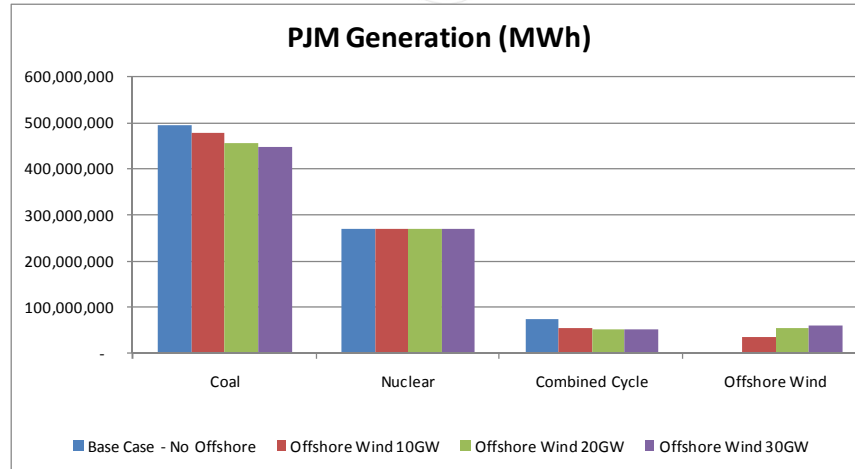
EWITS Code	EWITS Wind Site:13208	EWITS Wind Site:7142	EWITS Wind Site:4209
	Offshore Wind	Onshore Wind	Onshore Wind
Area	Jersey Central Power & Light	PPL Electric Utilities Corp.	Commonwealth Edison Co.
Installed Capacity (MW)	1,000	100	1,014
Max Annual (MW)	927	87	945
Average Annual (MW)	432	21	400
Energy Total Annual (MW)	3,799,028	184,630	3,511,423
Capacity Factor (MW)	43%	21%	39%
Capacity Credit (MW)	46%	9%	37%
Max August 4:00pm -5:00pm	921	27	945
Max June 4:00pm -5:00pm	922	50	937

Disclaimer: Capacity projections based on the EWITS data may be higher than average historical PJM data due to better technology and greater heights of wind turbines. Also, these projections are based on a single year. Long term performance may be different.

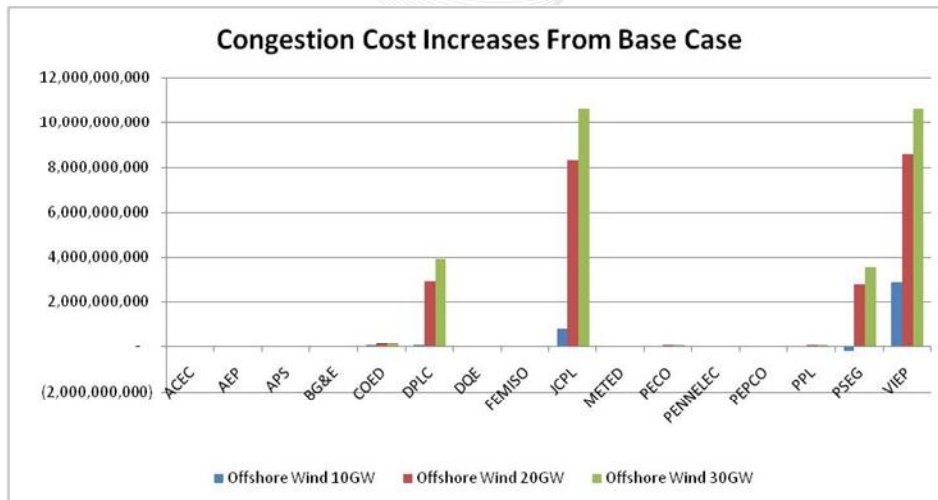
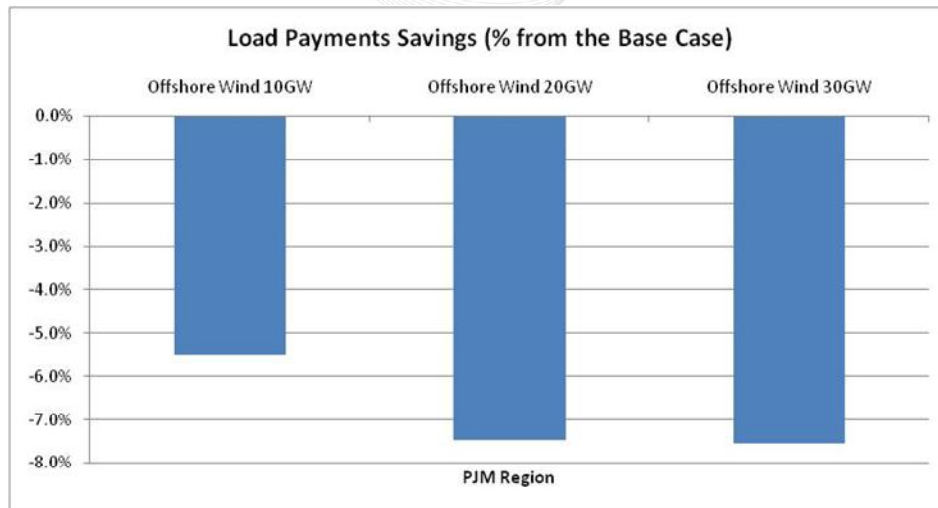
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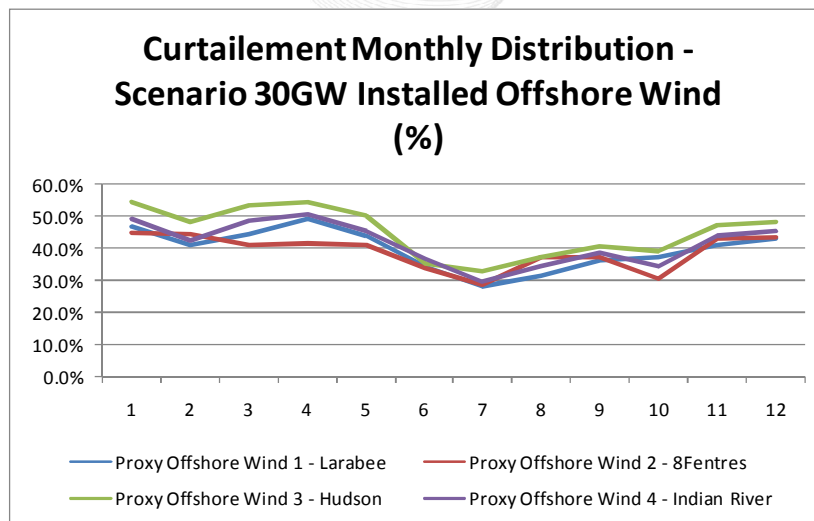
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Total Generation Change (%)			
Generation (MW)	Coal	Nuclear	Combined Cycle
Offshore Wind 10GW - Base Case	-3.7%	0.0%	-25.1%
Offshore Wind 20GW - Base Case	-7.9%	0.0%	-27.7%
Offshore Wind 30GW - Base Case	-9.5%	0.0%	-29.7%





- Further evaluate constrained facilities and potential upgrades
- Offshore grid to accommodate transfers between injection areas
- Additional reliability analysis
 - Validate monitored flowgates used in production cost simulations
 - NERC TPL-003
- Update topology in northern New Jersey

Attachment B

Company Planning Criteria

PLANNING GUIDELINES

GENERAL CRITERIA

The Company endeavors to maintain a high degree of reliability in electric service that satisfies the average customer's service requirements at a reasonable cost.

The North American Electric Reliability Corporation (NERC), and the eight (8) regional reliability councils, have developed mandatory, enforceable NERC Reliability Standards which must be complied with to assure reliable service to all areas of the United States. Additional criteria may be needed within an operating system to satisfy requirements specific to that area.

The Company is a member of the SERC Reliability Corporation (SERC) and is guided by the criteria set forth by that council. In addition, the following criteria are used in planning the Company's transmission system. These criteria apply to conditions of expected firm power transfers among the Company and its neighboring power systems and to the official company load forecasts, which are based on "normal" weather and projected, prevailing economic conditions.

As with generating capacity, reserve capacity must also be provided in the transmission system to recognize the effects of deviations from normal weather, load forecast uncertainty and variations in day to day operating conditions. In the application of the following criteria an allowance of 6% should be made in transmission facility loading (lines and transformers).

- Under normal loading conditions (All transmission facilities in service) no transmission facility should be loaded greater than its normal rating.
- The loss of any one transmission circuit should not cause the emergency rating(8 hour) to be exceeded on any of the remaining transmission facilities nor should it

cause the loss of any load, other than the load connected to that circuit, and the resultant voltage at any location on the 115 kV and 138 kV transmission system should not drop below 0.93 P.U. after transformer load tap changing equipment has readjusted nor should it drop below 0.93 P.U. on the 230 kV system and 1.01 P.U. on the 500 kV system.

- The loss of any two transmission circuits on a common right-of-way should not result in cascading outages or loss of load, other than that connected to the two circuits, and the resultant voltage at any location on the transmission system should not drop below 0.92 P.U. after transformer load tap changing equipment has readjusted nor should any overhead transmission facility be loaded to more than 30% above its emergency rating(8 hour) during the period required to make prompt power supply adjustments to reduce overload to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.
- The transmission system should be capable of supplying peak loads without exceeding the emergency rating(8 hour rating) on any facility for the following:
 1. The outage of the two largest generators in any generating station when all transmission facilities are in service.
 2. Critical System Conditions (The outage of the largest generator in any generating station which has the greatest effect on the transmission facilities being studied.) and the loss of any transmission facility.

During the above generation outages, other Company generating sources would be adjusted to make up the deficiency to the limit of available capacity.

- Stability requirements described in Table I of NERC Reliability Standards TPL-001-0 through TPL-004-0 must be met, at a minimum.

- The loss of three or more transmission circuits on a common right-of-way should not result in cascading outages beyond the load area immediately involved. The overall supply system to a major load area should be able to withstand the loss of all circuits on a common right-of-way and still supply most of the load in the area with tolerable voltage (at least 90% of nominal). A major load area would be an area similar to the Norfolk/Virginia Beach area or the Northern Virginia area.
- The loss of all generation at a generating station should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than 30% above its emergency rating(8 hour) during the period required to make prompt power supply adjustments to reduce overloads to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.
- The loss of a generating station substation, switching station or load substation should not result in cascading outages or intolerably low voltages (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than 30% above its emergency rating(8 hour) during the period required to make prompt power supply adjustments to reduce overloads to less than or equal to its emergency rating. Power supply adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.
- The outage of a critical transmission facility, which occurs while another critical transmission facility is already out of service, should not result in cascading outages or intolerably low voltage (less than 90% of nominal voltage) nor should any overhead transmission facility be loaded to more than 30% above its emergency rating(8 hour) during the period required to make prompt power supply adjustments to reduce overloads to less than or equal to its emergency rating. Power supply

adjustments can include loss of load (consequential and non-consequential) provided it does not exceed 300 MW.

- The transmission system should be capable of transferring reasonable amounts of power, in excess of firm purchases, sales and transfers, between and among the Company and the neighboring utilities with all transmission facilities in service or with one transmission circuit or transformer out of service and not exceed the maximum continuous rating of any remaining transmission facility. Any new facilities connected to the transmission system (greater than 20 MW) should not significantly decrement (greater than 5%) FCITC's for transfers between utilities.
- Combustion turbine generators should not be used for more than seven days to provide adequate service during the outage of a line or transformer. The assumed availability of combustion turbine generator units at any one time shall be in accordance with the following guide:

<u>Number of Units At The Location</u>	<u>Number Available At Any One Time</u>
2	1
3	2 smallest
4	3 smallest
5	3 smallest
6	4 smallest
Above 6	70% of Total Capacity

- Load on transmission radial lines without alternate supply should be limited to approximately 100 MW. A key factor in evaluating the load limitation on a radial transmission line is the distribution load that can be switched to circuits served from other sources. Unlike load served from a networked transmission line where a downed conductor or structure can be sectionalized allowing the remainder of the line to be reenergized before repairs are completed, load served from a radial transmission line can not be reenergized until all repairs to the line are completed.

Other factors include being able to perform maintenance on the radial line, outage history of line, load density and type, tie capability, etc.

- The transmission system must be examined frequently to assure that an effectively grounded system is maintained. A bus is considered to be "effectively grounded" when the following relationships are true:

- $X_0/X_1 \leq 3$

- $R_0/X_1 \leq 1$

This relationship assumes $R_1/X_1 = 0$, which is a worst case condition. If one or both of these relationships are not true, the effective grounding should be checked more precisely by referring to the curves found in the "*ABB Electrical Transmission and Distribution Reference Book*". The curves can be found in Chapter 18, page 626. The proper curve to use should be based on the actual R_1/X_1 ratio. Any set of ratios lying below the appropriate curve marked 80% will provide effective grounding for 80% lightning arresters standardly used on the Dominion syst